197137

STATE OF SOUTH CAROLINA

(Caption of Case)
Application of Duke Energy Carolinas, LLC for Authorization to Enter Into a Business Combination Transaction With Cinergy Corporation

BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

COVER SHEET

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DOCKETING INFORMATION (Check all that apply)

☐ Emergency Relief demanded in petition ☐ Request for item to be placed on Commission's Agenda expeditiously

☒ Other: Quarterly Market Monitoring Report for the Period covering October 2008 - December 2008

INDUSTRY (Check one)	NATURE OF ACTION (Check all that apply)		
☒ Electric	☐ Affidavit	☒ Letter	☐ Request
☐ Electric/Gas	☐ Agreement	☐ Memorandum	☐ Request for Certificatio
☐ Electric/Telecommunications	☐ Answer	☐ Motion	☐ Request for Investigatior
☐ Electric/Water	☐ Appellate Review	☐ Objection	☐ Resale Agreement
☐ Electric/Water/Telecom.	☐ Application	☐ Petition	☐ Resale Amendment
☐ Electric/Water/Sewer	☐ Brief	☐ Petition for Reconsideration	☐ Reservation Letter
☐ Gas	☐ Certificate	☐ Petition for Rulemaking	☐ Response
☐ Railroad	☐ Comments	☐ Petition for Rule to Show Cause	☐ Response to Discovery
☐ Sewer	☐ Complaint	☐ Petition to Intervene	☐ Return to Petition
☐ Telecommunications	☐ Consent Order	☐ Petition to Intervene Out of Time	☐ Stipulation
☐ Transportation	☐ Discovery	☐ Prefiled Testimony	☐ Subpoena
☐ Water	☐ Exhibit	☐ Promotion	☐ Tariff
☐ Water/Sewer	☐ Expedited Consideration	☐ Proposed Order	☐ Other:
☐ Administrative Matter	☐ Interconnection Agreement	☐ Protest	
☐ Other:	☐ Interconnection Amendment	☐ Publisher's Affidavit	
	☐ Late-Filed Exhibit	☒ Report	

POTOMAC ECONOMICS

QUARTERLY MARKET MONITORING REPORT ON DUKE ENERGY CAROLINAS, LLC

Fourth Quarter 2008

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

CONFIDENTIAL MATERIAL REDACTED

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I. OVERVIEW

This transmission monitoring report addresses the period from October 2008 through December 2008 for Duke Energy Carolinas, LLC (formerly Duke Power, a division of Duke Energy Corporation) ("Duke" or "the Company"). For the purpose of increasing confidence in the independence and transparency of the operation of the Duke transmission system, Duke proposed and FERC accepted in Docket No. ER05-1236-00 the establishment of an "Independent Entity" to perform certain OATT-related functions and a transmission monitoring plan that calls for an "independent transmission service monitor". The Midwest ISO was retained as the Independent Entity ("IE"), and Potomac Economics was retained as the independent transmission service monitor.

The scope of the independent transmission service monitor is established in the transmission monitoring plan. The plan is designed to detect any anticompetitive conduct from operation of the company's transmission system, including any transmission effects from the company's generation dispatch. It is also intended to identify any rules affecting Duke's transmission system which results in a significant increase in wholesale electricity prices or the foreclosure of competition by rival suppliers. As stated in the plan:

> The Market Monitor shall provide independent and impartial monitoring and reporting on: (1) generation dispatch of Duke Power and scheduled loadings on constrained transmission facilities; (2) details on binding transmission constraints, transmission refusals, or other relevant information; (3) operating guides and other procedures designed to relieve transmission constraints and the effectiveness of these guides or procedures in relieving constraints; (4) information concerning the volume of transactions and prices charged by Duke Power in the electricity markets affected by Duke Power before and after Duke Power implements redispatch or other congestion management actions; (5) information concerning Duke Power's calling for transmission line loading relief ("TLR"); and (6) the information provided by Duke Power used to perform the calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC").

To execute the monitoring plan, Potomac Economics routinely receives data from Duke that allows us to monitor generation dispatch, transmission system congestion, and the Company's response to transmission congestion (both its operational response and its business activities). We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to present the results of our monitoring activities and significant events on the Duke system[1] from October 2008 through December 2008.

A. Market Monitoring

Potomac Economics performs the market monitoring function on a regular basis, as well as performing periodic reviews and special investigations. Our primary market monitoring is conducted by way of regular analysis of market data relating to transmission outages, congestion, and system access. This involves data on transmission outages, transmission reservation requests, Available Transfer Capability ("ATC"), transmission line loading relief ("TLR") and curtailments or other actions taken by Duke to manage congestion. Analyses of this data aid in detecting congestion and whether market participants have full access to transmission service.

In addition to the regular monitoring of outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather events that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on data Duke provides, as well as other data that we routinely collect. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion and the use of schedule curtailments in order to detect potential competitive problems. Congestion is identified by TLR events and schedule curtailments[2] on Duke's transmission system. Third, we evaluate the disposition of transmission service requests and TTC to analyze transmission

1 As allowed for in the monitoring plan, certain anomalous findings related to general market conditions, TTC, and transmission outages were shared with Duke to obtain clarification prior to submission to FERC and the state commissions.

2 When we refer to schedule curtailments, we include TLR events because schedule curtailments are the main method used under the TLR procedures to manage congestion.

access and to detect events on the Duke system that require closer analysis. Finally, to monitor for anticompetitive conduct, we examine periods of congestion and evaluate whether Duke operating activities are consistent with anticompetitive conduct. The operating activities that we evaluate are wholesale purchases and sales, generation dispatch and availability, and transmission availability.

In addition to our periodic reviews, we may from time-to-time be asked to or deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred during the time period of this report.

B. Summary of Quarterly Report

The following subsections summarize the findings of our monitoring of Duke's operations during the quarter.

1. Wholesale Prices and Transactions

Prices. We evaluate regional wholesale electricity prices in order to provide an overview of general market conditions. Over the course of the study period, electricity prices have been stable and exhibited a moderate correlation with peak load and natural gas prices. The correlation with natural gas is strong for this time of year.

Sales and Purchases. Duke engages in wholesale purchases and sales of power on both a short-term and long-term basis. Duke short-term [redacted] to use it.

2. Transmission Congestion

We use TLR events in the vicinity of Duke and schedule curtailments initiated by Duke to identify periods of congestion. Duke manages transmission congestion with generation redispatch, transmission system reconfiguration, and schedule curtailments.[3]

[3] We use the term schedule loosely in this context. It is actually e-tags that are curtailed. Each e-tag represents a physical sequence and time series of schedules. Therefore, one e-tag may have multiple schedules comprising it. Also, sometimes the same e-tag is curtailed more than once.

Of these, schedule curtailments have the most direct impact on market access and outcomes. Duke operates primarily on a contract path basis. A common situation in which Duke uses curtailments is when unscheduled firm reservation rights are released to the market and scheduled for non-firm use, but are then displaced when the higher priority firm reservation holders subsequently submit schedules. The displaced non-firm schedules are curtailed. Curtailments also can occur when the paths reach their contract limits even though they may not be heavily loaded with physical flow. During the period of study, there were fourteen curtailments initiated by Duke and three TLR events in the region.

All curtailments regardless of their basis are important because they have the same impact in reducing transmission access. Only schedules curtailed based on physical flow, however, are potentially influenced by generation operations. We analyzed the impact of Duke's generation operations on the TLR events and physical flow based tag curtailments. We did not find that Duke's dispatch of generation contributed to the events.

3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing Duke's transmission network. If requests for transmission service are frequently denied unjustifiably, this may indicate an attempt to exercise market power. The volume of accepted requests was comparable to the previous quarter. The approval rates were also relatively high, averaging 99.6 percent over the period of study. Given the high volume of service sold and the low level of refusals, we do not find a pattern in the disposition of transmission requests that indicates restrictive access to transmission.

For the period of study, we identified "CPLE to CPLW"[4], "PJM to Southern Company" and "Southern Company to PJM" as key transmission paths, including the segments that source or sink from Duke. We studied these paths because of the volume of refused

4 CPLE and CPLW refer to the eastern and western portions of Progress Energy's service territory in North and South Carolina (formally known as Carolina Power and Light).

transmission service requests and the frequency of curtailed transmission schedules. We examined TTC calculations on these paths for days when ATC became unavailable. Our review of these days determined that the reductions in TTC are justified based on the day-ahead study results.

4. Potential Anticompetitive Conduct

Wholesale Sales and Purchases. We examined the real-time sales and purchases that delivered during the period of study. We focus on real-time bilateral contracts because these best represent the spot price of electricity in markets served by Duke and are the means Duke would likely use to profit by affecting wholesale electricity prices. Under a hypothesis of market power, we would expect higher sales prices or lower purchase prices during times when transmission congestion arises. Daily average transaction prices ranged between $[redacted]/MWh and $[redacted]/MWh. There were days when Duke's net sales position could have potentially benefited from the congestion. We scrutinized these days when we evaluated generation and transmission operations and did not find evidence of anticompetitive conduct.

Generation Dispatch and Availability. To further evaluate competitive issues, we examine Duke's generation dispatch to determine the extent to which congestion may be caused or exacerbated by uneconomic dispatch. Congestion can result even when Duke or any utility dispatches its units in a least-cost manner. Such congestion does not raise competitive concerns. If an unjustified departure from least-cost dispatch ("out-of-merit" dispatch) occurs and causes congestion, further analysis is warranted to determine whether the Company's conduct raises competitive concerns.

Using an estimated supply curve, we analyze Duke's actual dispatch to determine whether the actual dispatch departed significantly from what we estimate to be the economic dispatch. We then evaluate the contribution that the out-of-merit dispatch makes to flows on congested transmission paths to determine if congestion was either created and/or exploited by Duke. Our investigation into the congestion events found that generation dispatched out-of-merit had no impact on curtailed paths. Consequently, we do not find evidence of anticompetitive conduct.

We also conducted an analysis of potential economic and physical withholding to further evaluate generation operations. Indicators of potential economic and physical withholding were minimal and not indicative of anticompetitive conduct.

Evaluation of generation outage rates did not reveal evidence that generation outages were associated with anticompetitive conduct.

Transmission Availability. Finally, we evaluate Duke's transmission outage events in order to determine whether these events may have unduly impacted market outcomes during the study period. We find no evidence of anticompetitive conduct.

5. Conclusions

Our analysis did not indicate any potential anticompetitive conduct from operation of the company's transmission system or generation.

C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding any special investigation into Duke's market behavior, nor have we detected any conduct or market conditions that would warrant a special investigation.

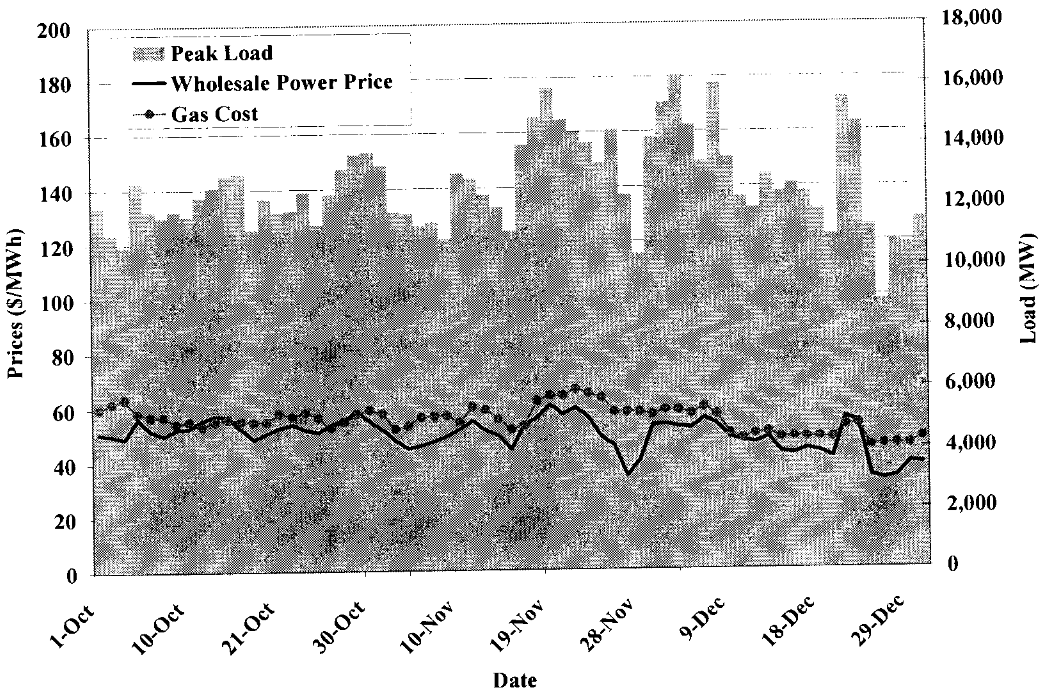
II. Wholesale Prices and Transactions

A. Prices

We evaluate regional wholesale electricity prices in order to provide an overview of general conditions in the market in which Duke operates. Examining price movements can provide insight into specific time periods that may merit further investigation, although they are not definitive indicators of anticompetitive conduct.

Duke is not part of a centralized wholesale market in which transparent spot prices are produced. Wholesale trading in the areas in which Duke operates is conducted under bilateral contracts. Bilateral contract prices are collected and published by commercial data services such as Platts, which we use for this report. Platts publishes prices at various pricing points, including a price for the VACAR (Virginia, Carolinas) subregion of the South East Reliability Council (SERC), which includes Duke's control area. Figure 1 shows the bilateral contract prices for VACAR along with other market indicators.

Figure 1: Wholesale Power Prices and Peak Load October 2008 through December 2008

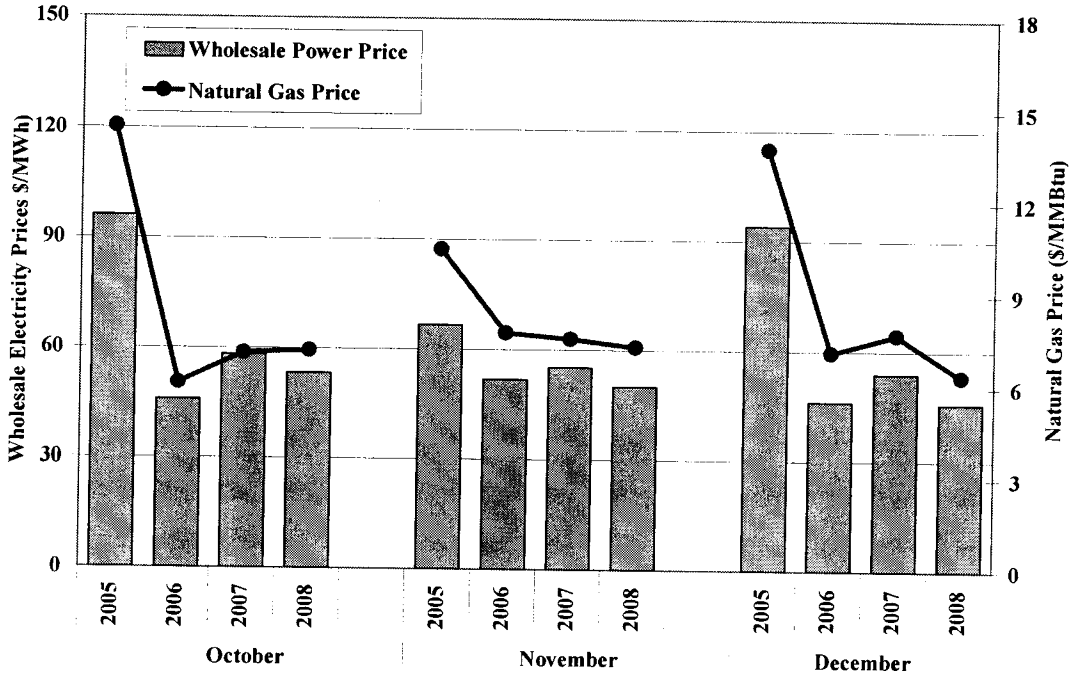


We show system load data because of its expected correlation with power prices. We show natural gas prices because natural gas-fired units are most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's marginal costs. We use the daily price of natural gas deliveries by Transco at its Zone 5 location, a main pricing point for natural gas purchases by Duke. We translate this natural gas price to a power cost assuming an 8,000 btu/kWh heat rate. This number roughly corresponds to the fuel cost portion of the operating cost of a natural gas combined cycle power plant, which should generally correspond to the competitive price for power.

Prices ranged from $32/MWh to $61/MWh over the study period. The correlation between power prices and load was moderate (61 percent) and the correlation between power prices and natural gas prices was also moderate (68 percent). The strength of the correlation with natural gas prices was stronger than expected given the decreased reliance on natural gas-fired resources during cooler fall and early winter months. The temperatures in the region were normal for the quarter on average. However, October and November were about two to three degrees Fahrenheit below normal and December was about four degrees Fahrenheit above normal. The precipitation was about 80 percent of normal.

The next analysis compares the average VACAR power prices for each month in the study period with the corresponding month of the previous three years. Results are shown in Figure 2 together with the average of the daily Transco Zone 5 natural gas prices. As the figure shows, electricity prices have generally been correlated with natural gas prices over time.

Figure 2: Trends in Monthly Electricity and Natural Gas Prices October 2005 – December 2008



Overall, our evaluation of wholesale electricity prices in the Duke region did not indicate a time period that merits particular attention based on pricing patterns.

B. Sales and Purchases

Duke engages in wholesale purchases and sales of power. These transactions are both firm and non-firm in nature. Figure 3 summarizes Duke's sales and purchase activity for trades that delivered during the study period. We consider only short-term trades because we are interested in transactions that could have allowed Duke to benefit from any potential market abuse during this time period. Short-term transactions include all transactions that are done in the day-ahead or real-time markets. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion. Additionally, short-term transaction prices are good indicators of wholesale market conditions during periods of congestion.

Figure 3: Summary of Duke Sales and Purchases
Fourth Quarter of 2008

Redacted

As the figure shows, Duke's [redacted] transactions. This is not uncommon for this time of year. During the quarter, Duke was [redacted] of capacity. It was [redacted] transactions. At a broad level, the fact that Duke's [redacted] In general, a market participant exercising market power [redacted] we evaluate the prices of real-time transactions during congested periods in Section V.A to detect potential anticompetitive conduct.

III. TRANSMISSION CONGESTION

A. Overview

Duke is located in the SERC region of the North American Electric Reliability Council ("NERC"). NERC is certified as the Electric Reliability Organization ("ERO") in the United States as of July 20, 2006. SERC is divided geographically into five subregions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. VACAR is further divided into two intraregional coordination groups including VACAR North and VACAR South for the establishment of Reliability Coordinators ("RC"). Duke is within the VACAR South coordination group along with five other balancing authorities: Progress Energy Carolinas, Inc., South Carolina Electric & Gas Company, South Carolina Public Service Authority (Santee Cooper), Southeastern Power Administration, and Yadkin (a division of Alcoa Power Generation Inc).

Procedures to manage transmission congestion are implemented by the VACAR South Reliability Coordinator. The activities covered in these procedures include performing day-ahead and real-time reliability analysis, working with participants to correct System Operating Limit ("SOL") and Interconnection Reliability Operating Limit ("IROL") violations, and managing TLR events.

The VACAR South Reliability Coordinator utilizes an "Agent" to perform Reliability Coordination tasks. Duke, in addition to being a member of the VACAR South coordination group, is contracted to serve as Agent to perform the duties of Reliability Coordinator for itself and the other five VACAR South member companies. The transmission monitoring plan calls for monitoring Duke's operation of its transmission system to identify anticompetitive conduct, including conduct associated with system operations and reliability coordination.[5] Our monitoring of such conduct is limited to conduct associated with Duke's transmission system and does not extend to Duke's activities as Agent for the VACAR South Reliability Coordinator.

[5] See Transmission Service Monitoring Plan, Section 1.2.

B. Transmission Congestion

We monitor Duke for potential anticompetitive operation of generation or transmission facilities that may create transmission congestion or otherwise create barriers to rival companies' access to the markets. Congestion in the operating horizon is identified through real-time contingency analysis ("RTCA"). In this process, line-loadings are monitored to keep them within ranges whereby a system outage or "contingency" can be safely sustained. If the line-loadings exceed this safe range (called the system operating limit or "SOL"), then the lines are relieved[6] through generation redispatch, reconfiguration, schedule curtailments, and/or load reduction.[7]

Congestion between balancing authorities is monitored and managed through the use of Transmission Loading Relief procedures. These procedures invoke schedule curtailments, system reconfiguration, generation redispatch, and load shedding as necessary to relieve congestion by reducing flows below the first-contingency transmission limits on all transmission facilities. Duke's general practice is to curtail schedules and redispatch generation as needed to manage congestion without invoking TLR procedures, but Duke can impact or be impacted by TLR events invoked by neighboring areas.

Schedule curtailments can constitute anticompetitive conduct if they are not justified. They cause an immediate reduction in market access that could affect market outcomes. Accordingly, these congestion events are the basis for our screening of Duke's generation and transmission operations.

For the purposes of our analysis, we consider two types of schedule curtailments. One we refer to as "flow-based curtailments", which are curtailments to accommodate the actual physical flows on facilities as identified by the RTCA. TLR events are included with flow-based curtailments when we conduct our analysis of operating activities. The other is "contract-path-based curtailments" which are not related to physical flows but rather to contract path limits. Contract-path-based schedule curtailments may be implemented to stay within contract limits even though the path may not be physically

6 Some contingency overloads do not require action to be taken because they do not have the potential to cause cascading outages, substantial loss of load, or major equipment damage.

7 System reconfiguration actions may include opening tie line breakers, which can cause TTC to go to zero, inducing schedule curtailments.

congested. While this has the same effect on market access, these curtailments are not caused by the operation of generation.

Contract-path based curtailments are implemented when transmission conditions reduce total transfer capability below the level of existing schedules on the contract path, which results in the curtailment of non-firm and possibly firm schedules. Contract-path based curtailments are also the result of non-firm service being displaced to accommodate a schedule under a firm reservation. Since these conditions are not affected by generation operations, we only use the flow-based curtailments in our analysis of generation operations.

During the period of study, there were fourteen curtailments initiated by Duke and three TLR events in the region, each initiated by PJM. Of the curtailments, nine were due to TTC reductions caused by a line outage in the PJM area, and five were due to TTC reductions caused by a line outage in the Progress Energy area. As mentioned previously, we included the three nearby TLR events in our analysis. These congestion events will be evaluated below.

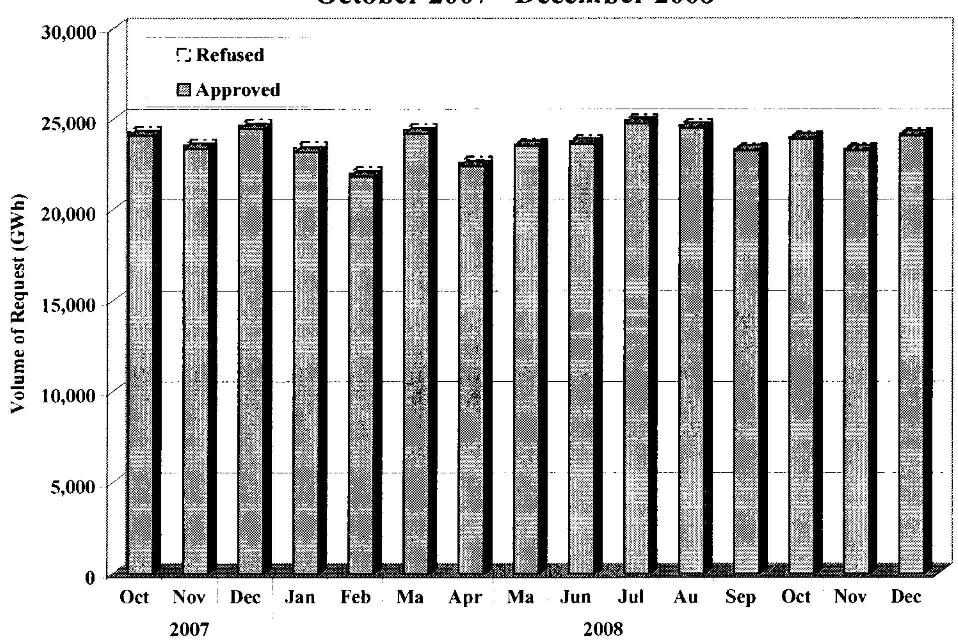
IV. TRANSMISSION ACCESS

A main component of the transmission monitoring function is to evaluate transmission availability on the Duke system. In this section, we evaluate access to transmission by analyzing the disposition of transmission service requests. The patterns of transmission requests and their disposition are helpful in determining whether market participants have had difficulty accessing Duke's transmission network.

In order to make this evaluation, we calculate the volume of requested capacity that spanned the time period under study. For example, if a request was approved in January for service in June, we categorize that as an approval for June. Because requests vary in magnitude and duration, we assign a total monthly volume (GWh) associated with a request, which provides a common measure for all types of requests. Hence, a yearly request for 100 MW has rights for every hour of the month for which the request spans, just a like a monthly request. A request covering less than the entire month is assigned the hours between its stop and start date.

Figure 4 shows the breakdown of transmission service requests in each month from October 2007 through December 2008 and summarizes the disposition of the requests.

Figure 4: Disposition of Requests for Transmission Service on the Duke System October 2007 - December 2008



The figure shows that the total volumes of approved requests during the period have decreased slightly although the approval rate remains very high compared to the prior quarter and the same months from the prior year. The volumes of refused requests have also decreased. Although it is not obvious from the figure, the refusal volume was only 285 GWh during the fourth quarter of 2008, which is a reduction from the refusal volume of 414 GWh during the third quarter of 2008. Additionally, the approval rate of transmission service requests was relatively high over the study period, averaging 99.6 percent. Given the low volume of refused requests and high approval rates, we do not find evidence that Duke has restricted access to transmission capability.

To evaluate the disposition of transmission requests further, we compare the volume of transmission requests over the study period by increment of service to the requests from the corresponding period a year prior. This comparison is shown in Figure 5.

Figure 5: Disposition of Transmission by Duration of Service

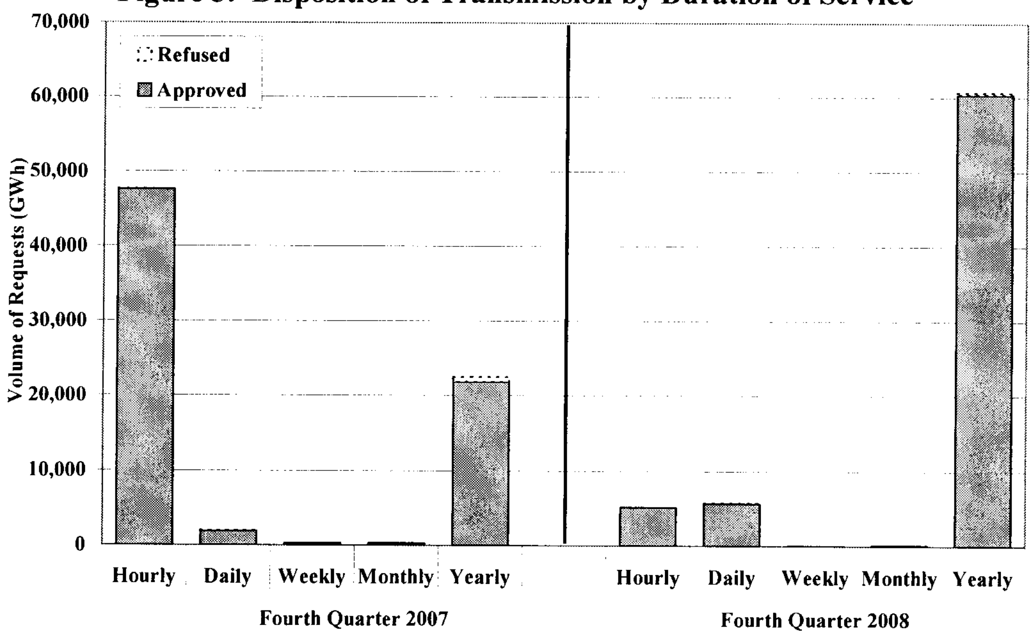


Figure 5 indicates a decrease in approvals in the hourly category of service and an increase in the daily and yearly categories of service. This shows an overall slight decrease in approvals with a shift from hourly to daily and yearly service. The volume of refusals is less than half of what it was in the same period of the prior year. These increases in approval volumes for yearly service further support our conclusion that transmission access has not become more restrictive.

Our next analysis focuses on TTC for key contract paths. We assess TTC reductions that may limit market access. As mentioned above, Duke's primary means of managing congestion within its system is to forecast congestion using day-ahead studies[8], and then reduce the TTC as a means of reducing the schedules that cause the forecasted congestion. The day-ahead study is conducted by the IE using data provided by Duke. The study can result in reductions in TTC on certain paths. To avoid curtailing firm schedules, TTC is not reduced below firm schedule amounts even if the day-ahead studies predict congestion at those levels.

This process creates an incentive for Duke to provide forecasts that reduce TTC and thereby exclude competitors. We monitor this process by selecting cases where the ATC was at or near zero. We then review the TTC associated with these cases to determine whether a reduction of TTC could have caused the ATC to become unavailable. This result raises concerns of potentially anticompetitive behavior. Thus, we make further examination to determine if the reduction in TTC was justified. We monitor this process at two levels. First, we simply check the day-ahead study results to ensure the process is being implemented properly. Then we assess the accuracy of the process.

Based on the volume of refused transmission service requests ("TSRs") and the frequency of schedule curtailments, we identify the key paths are those with either PJM, Duke or Southern Company as sources or sinks, as well as the "CPLE to CPLW" path. To evaluate the transmission capacity available on these paths, we analyze as a proxy the wheel-through paths of "Southern Company to PJM", "PJM to Southern Company", and "CPLE to CPLW". We then identify the limiting segments for further review.

Using the wheel-through path as a proxy is reasonable because Duke's practice, as implemented by the IE, for determining the TTC on wheel-through paths is to use the minimum between the TTC on the subpath that sinks into the Duke system and the subpath that sources from the Duke system. Hence, the "PJM to Southern Company" TTC would be the minimum of the "PJM to Duke" TTC and the "Duke to Southern

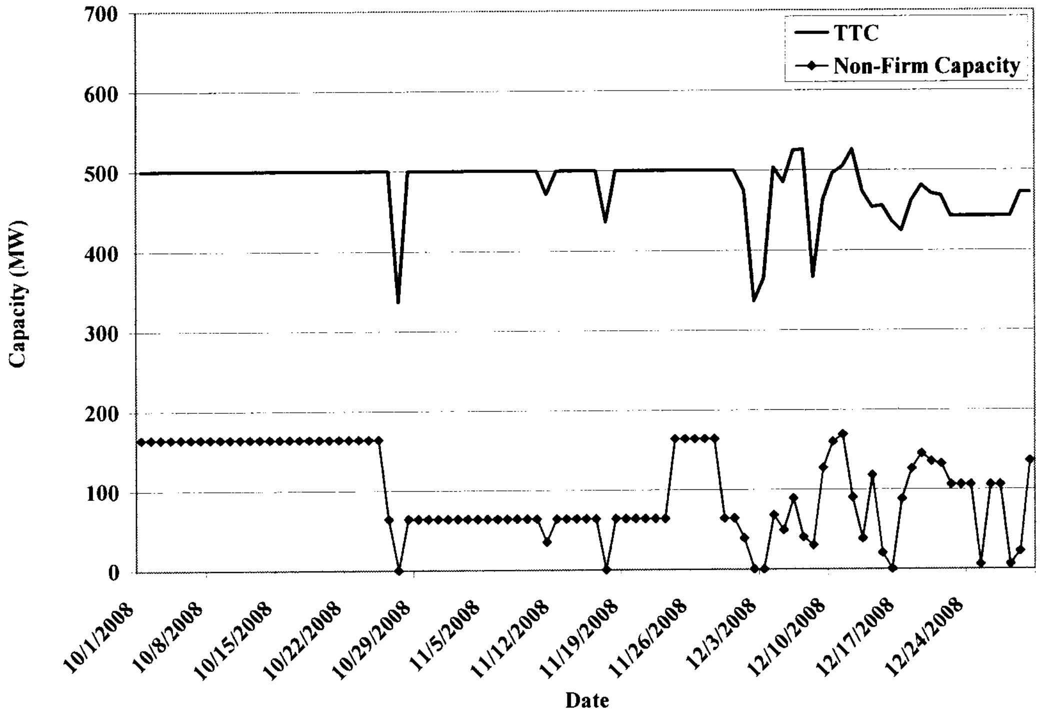
8 The accuracy of day-ahead studies is limited due to being based on uncertain parameters such as system load and interchange.

Company" TTC. Given this practice, it is reasonable to evaluate TTC effects by reviewing the wheel-through paths.

Duke's practice for determining wheel-through TTCs can produce overly conservative results, as noted in the First Quarter 2008 Market Monitoring Report. This occurs when one subpath of the wheel-through loads a limiting component and the second subpath unloads that same component. We had recommended in the First Quarter report that the IE consider whether it is feasible to evaluate TTC on entire paths when implementing curtailments. It is our understanding that Duke and the IE are evaluating the details involved in modifying the practice.

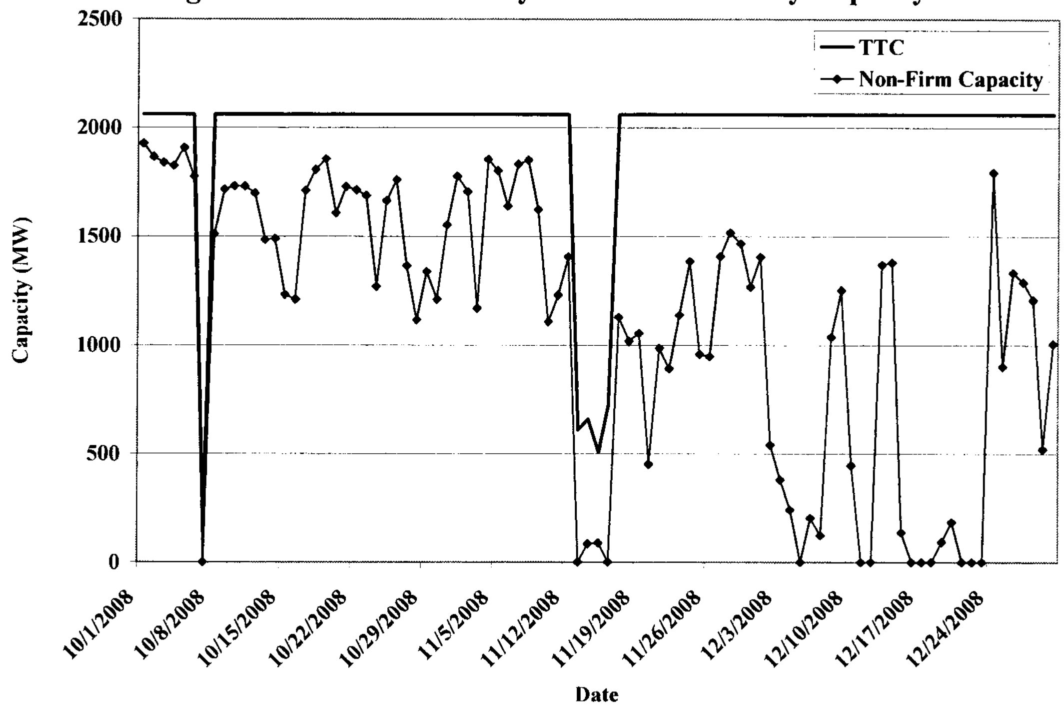
We evaluated the "CPLE to CPLW" path and identified the limiting segment as "Duke to CPLW". This segment is shown in Figure 6. In the figure, we show the minimum TTC and ATC for each day. As the figure shows, there were seven days when the ATC was at or near zero, while there was a reduction in TTC at the same time. These instances are significant because they may represent Duke improperly reducing TTC in order to reduce competitors' access. However, there were refusals of transmission service for only two of those days. There were no tag curtailments on this path over the quarter. The TTC postings are consistent with the day-ahead study results, and the refusals appear to be consistent with the ATC postings. We review the justification of outages that may have contributed to the low TTC postings in the transmission outages section of this report.

Figure 6: DUK to CPLW Daily Minimum of Hourly Capacity



Next we consider the "Southern Company to PJM" Path. The TTC on this path was near the contract path limit of 2059 MW for all but five days (October 7, and November 13 through November 16). On three of these five days, the ATC was zero. There were other days in December when the ATC was zero, but since the TTC was high for those days, we find that this path was available for market activity. Hence, our concern is with the three days when ATC was zero and TTC was also significantly reduced. To assess this, we reviewed the limiting segment identified as "Duke to PJM". This segment is shown in Figure 7 below.

Figure 7: DUK to PJM Daily Minimum of Hourly Capacity



The "PJM to Southern Company" path TTC and ATC are shown in Figure 8. The general pattern of the TTC is the same as in the "Southern Company to PJM" path. Taken together, the ATC shows a market interest in transmission rights from "PJM to Southern Company" in October and November. This market interest reverses in December to "Southern Company to PJM". This is apparent because the ATC is near zero in one direction and plentiful in the other, which shows that market participants are buying transmission service consistent with differences in the seasonal demand between the northern and southern portions of the interconnect. In some of these cases, the TTC was reduced. To evaluate these cases, we examine the "PJM to Duke" and the "Duke to Southern Company" path segments in Figure 9 and Figure 10, respectively.

Figure 8: PJM to SOCO Daily Minimum of Hourly Capacity

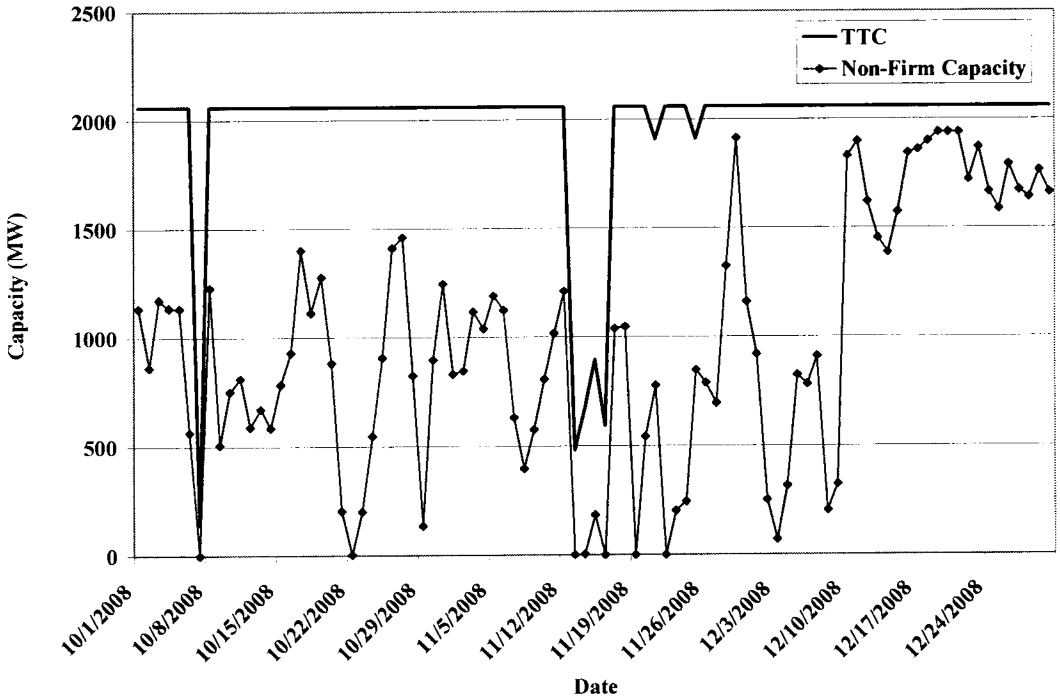


Figure 9: PJM to Duke Daily Minimum of Hourly Capacity

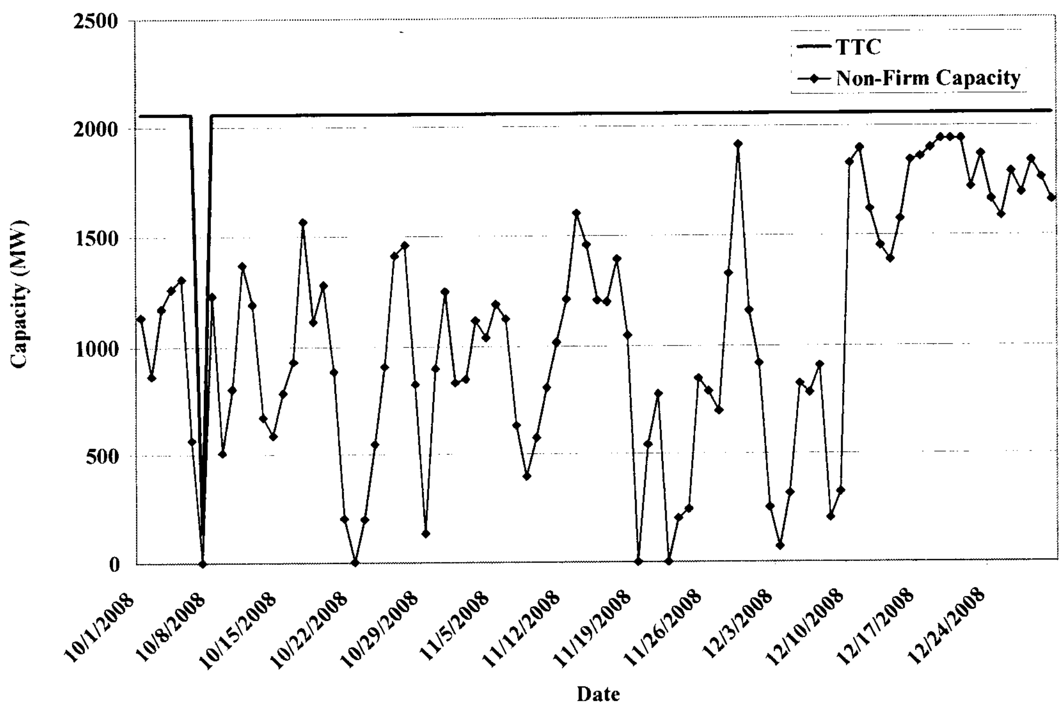
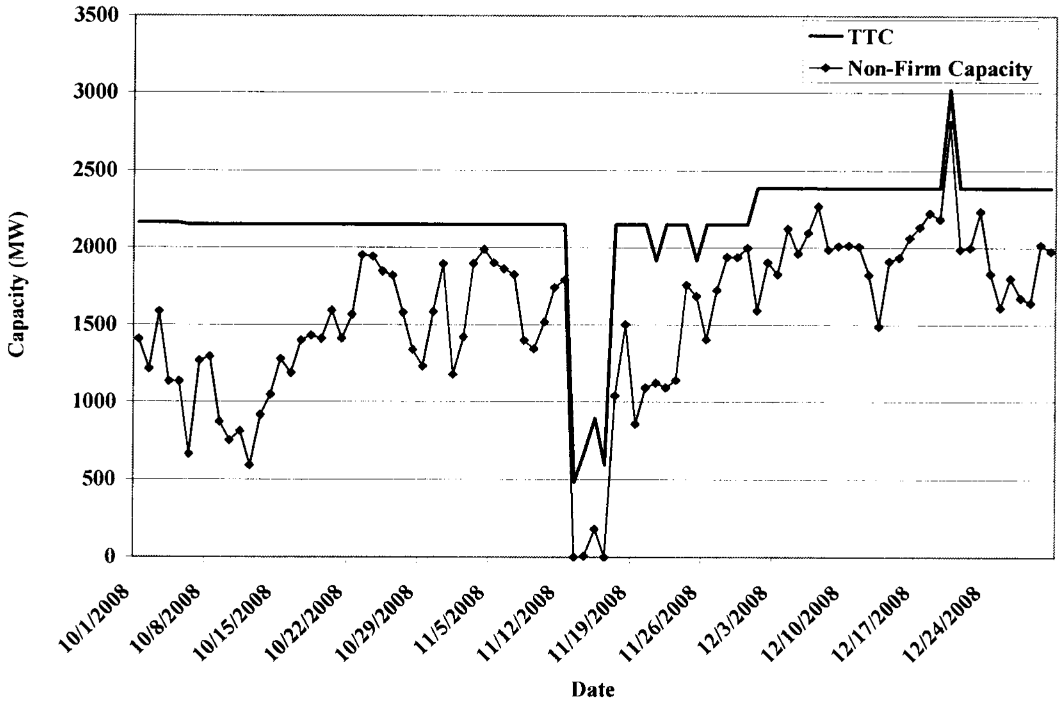


Figure 10: Duke to SOCO Daily Minimum of Hourly Capacity



From the two figures above, it is apparent that limitations to access for the "PJM to Southern Company" wheel-through are caused by the combined effect of both path segments. The low TTC in October is from the "PJM to Duke" segment, and the low TTC in November is from the "Duke to Southern Company" segment. We evaluated the five days with low TTC and found the following:

- October 7: There was a scheduled outage of the [redacted] The resulting drop in TTC on the interface led to nine curtailments. The curtailments are justified because Duke did not cause or contribute to the event. However, the curtailments may have been avoidable had the scheduled outage been reflected in the TTC postings further in advance.

- November 13 through November 14: There was an outage [redacted] This caused TTC reductions for the export paths "Duke to PJM" and "Duke to Southern Company".

Using Duke's method for setting wheel-through path TTCs as the minimum of the segments, the TTCs for "PJM to Southern Company" and "Southern Company to PJM" were also reduced. We do not view Duke as causing or contributing to the event. The TTC was adjusted according to their process. We reviewed the real-time contingency analysis results for these same components and found them to not be in violation of operating limits in the real-time. Moreover, our review of the real-time line loadings finds that post-contingent loadings would not have exceeded 55 percent of the limit. Hence, the reduction in TTC was justified based on the day-ahead study results, but these study results did not accurately predict real-time conditions.

Our review of Duke's activity relating to reducing TTC does not show that access was limited in an anticompetitive manner. However, there is room for improvements in incorporating scheduled transmission outages into the TTC postings in a timelier manner and in day-ahead study accuracy.

V. MONITORING FOR ANTICOMPETITIVE CONDUCT

In this section, we report on our monitoring for anticompetitive conduct. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either Duke's transmission assets or its generation assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze Duke's wholesales sales in the first subsection below, its dispatch of generation assets in the second subsection, and Duke's transmission operations in the third subsection.

A. Wholesale Sales and Purchases

We examine transaction data to determine whether the prices at which Duke sold or purchased power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If Duke were engaging in anticompetitive conduct to create congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the real-time bilateral transactions made by Duke using Duke internal records. We focus on real-time transactions because anticompetitive conduct is likely to be more successful in the real-time market.

Competition is facilitated by the ability of rivals to gain market access by reserving and scheduling transmission service. Access will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over-scheduled or physically overloaded. If Duke's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments.

Recall that curtailments can be flow-based (i.e., the result of flows exceeding the system operating limit), or contract-path-based (i.e., the result of contract-path reservations exceeding the path rating). For our analysis of Duke's sales, we use both types of curtailments. This is reasonable because both types of curtailments reduce market access.

Moreover, Duke has the direct ability to affect both flow-based curtailments and contract-path-based curtailments. It can affect flow-based curtailments through operating activities and it can affect contract-path-based curtailments by unjustifiable schedule reductions. By screening the curtailment data against sales activities, we can focus attention on events that merit further inquiry.

Figure 11 shows the daily average prices received by Duke for real-time bilateral sales and purchases. The blue shading indicates days when curtailments occurred that could have potentially benefited Duke's position in the real-time bilateral markets

To link curtailment events with days when curtailments could have potentially benefited Duke's position in the real-time bilateral markets, we calculate a measurement called the maximum daily effective market position ("Max Effect"). The Max Effect indicates Duke's trade volume that could have potentially benefited from a particular curtailment. Days with curtailments coincident with high Max Effect levels are days when the curtailments could have potentially allowed Duke to exploit the effect of the curtailment. These days are further evaluated to determine if the transactions were done at pricing levels that are consistent with a pattern of anticompetitive conduct.

The Max Effect is calculated in two steps. First, for each hour and for each constraint and delivery point, we calculate a shift-factor-weighted[9] volume of trades by summing the product of the shift factors and the net trade volumes (purchases minus sales). For each hour and each constraint, the values are summed across all delivery points. Second, from this set of values, we select the maximum value for each day. If the maximum value is positive, it appears on Figure 11.

[9] The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path. Shift factors between -.01 and .01 are set to zero.

Figure 11: Prices for Duke Sales and Purchases
October 2008 – December 2008

Redacted

The weighted average daily prices of Duke's sales range between $[redacted]/MWh and $[redacted]/MWh. The volume-weighted average daily sales price was $[redacted]/MWh. On days with curtailments that may have benefited Duke's net sales position, the average sales price was $[redacted]/MWh. The weighted average daily prices of Duke's purchases range between $[redacted]/MWh and $[redacted]/MWh. The volume-weighted average daily purchase price was $[redacted]/MWh. On days with potentially beneficial curtailments, the average purchase price was $[redacted]/MWh. Overall these statistics do not raise potential competitive concerns.

We evaluated the three days that had a positive Max Effect in more detail and found the following:

- [redacted]: Duke had positions [redacted] that may have been impacted by the loss of the tie-line. However, since an open tie-line restricts flow in both directions, the impact is not necessarily beneficial.

- [redacted]: Duke had [redacted] that could have benefited from the reduced TTC and curtailments of other companies' [redacted].

- [redacted]: Duke had [redacted] could have benefited from the reduced TTC and curtailments of other [redacted] schedules.

We will evaluate these three days below as we evaluate other aspects of potential anticompetitive conduct.

B. Generation Dispatch and Availability

To further evaluate whether Duke's conduct raises any anticompetitive concerns, we examine the company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch of generation by Duke. We conduct two analyses. We first determine the hourly quantities of out-of-merit dispatch and the degree to which the out-of-merit dispatch contributed to flows on congested transmission paths. If the contribution is significant, further investigation of these times may be warranted. We use flow-based curtailments because, as explained more below, these types of curtailments (as opposed to contract-path-based curtailments) are the ones that would result from unjustified out-of-merit dispatch. Second, we examine the "output gap", which measures the degree to which Duke's generation resources were not fully scheduled when prevailing prices exceeded the marginal cost of running the unit.

1. Out-of-Merit Dispatch and Curtailments

Congestion can be a result of limits on the transmission network when utilities dispatch their units in a least-cost manner. This kind of congestion does not raise competitive concerns. If a departure from least-cost dispatch ("out-of-merit" dispatch) is unjustifiable and causes congestion, it raises potential competitive concerns.

We pursue this question by measuring the out-of-merit dispatch on the Duke system. In our analysis, we consider a unit to be out-of-merit when it is dispatched when a lower-cost unit is not fully loaded at the same time. To identify out-of-merit dispatch, we first estimate Duke's marginal cost curve or "supply curve".[10] We use incremental heat rate curves, fuel

10 We use the term marginal cost loosely in this context. The value we calculate is actually the *marginal running cost* and does not include opportunity costs, which may include factors such as outage risks or lost sales in other markets.

cost, and other variable operations and maintenance cost data provided by Duke to estimate marginal costs. This allows us to calculate marginal costs for Duke's units. We order the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings.

Figure 12 shows the estimated supply curve for a representative day during the time period studied.

Figure 12: Duke Supply Curve

Redacted

Note: Excluding Approximately [redacted] of Nuclear and Hydro Capacity.

The dispatch analysis excludes nuclear and hydro units because their operation is not primarily driven by current system marginal operating costs. Nuclear resources rarely change output levels and the opportunity costs associated with hydroelectric resources make it difficult to accurately estimate their costs.

As the figure shows, the marginal cost of supply increases as more units are required to meet demand, as expected. The highest marginal cost is over $[redacted]MWh. We use each day's estimated marginal cost curve as the basis for estimating Duke's least-cost dispatch for each hour in the study period.

In general, this will not be completely accurate because we do not consider all operating constraints that may require Duke to depart from our estimate of least-cost dispatch. In particular, this analysis does not model generator commitments, assuming instead that all available generators are online. While market monitoring resources could have been expended to refine the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively-low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a coal delivery problem that prevents a coal plant from being fully utilized. Because the coal plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to operate the plant at reduced load to conserve coal can cause the out-of-merit values to be overstated.

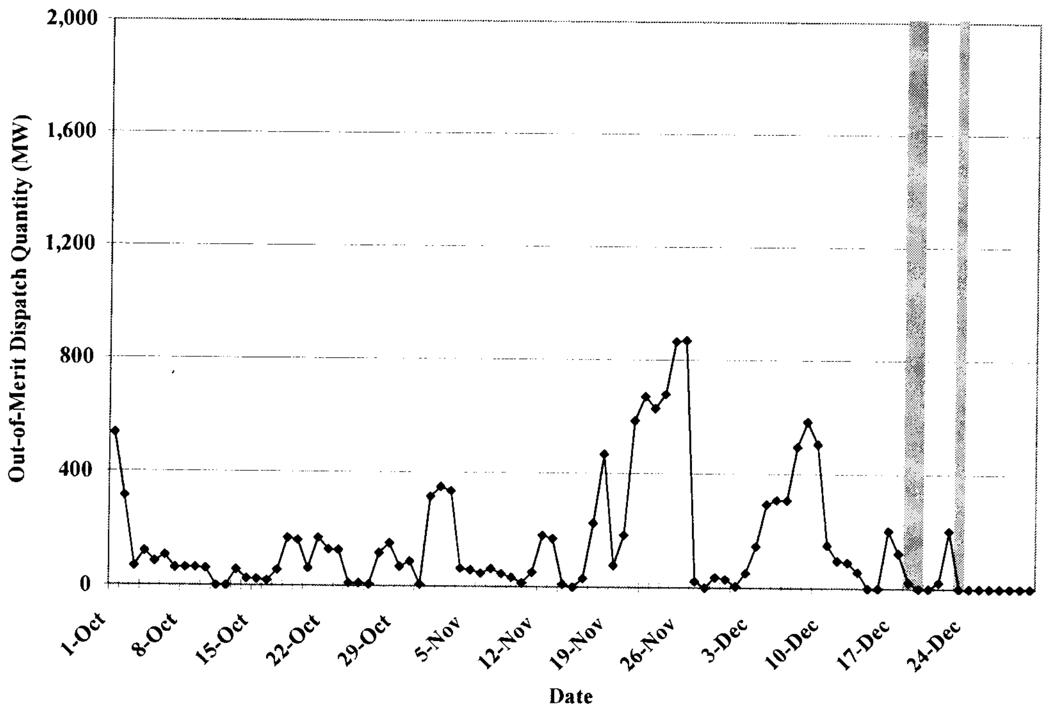
Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market.

Overall, our analysis will tend to overstate the quantity of generation that is truly out-of-merit. Accordingly, the accuracy of a single instance of out-of-merit dispatch is not as important as the trend or any substantial departures from the typical levels.

In our analysis, we seek to identify days with significant out-of-merit dispatch that coincides with transmission congestion. Congestion is indicated by flow-based schedule curtailments. Flow-based curtailments are those that are taken close to real-time in order to prevent physical flows from exceeding system operating limits. Out-of-merit dispatch can be used to affect these flows and create the need for curtailments, potentially limiting competition in specific locations. Contract-path based curtailments, on the other hand, are the result of reserved rights on the contract paths and are unaffected by real-time dispatch.

Figure 13 shows the daily maximum "out-of-merit" dispatch for the peak hours of each day in the study period.

Figure 13: Out-of-Merit Dispatch and Congestion Events October 2008 – December 2008



Also shown in the figure are days with flow-based curtailments represented by blue bars. The curtailments were [redacted] on three days. For these days, the out-of-merit dispatch displayed is the maximum taken over just the hours of the day with curtailments. We determined whether out-of-merit dispatch loaded the curtailed path. However, out-of-merit dispatch had no impact on the curtailed path. Consequently, we do not find evidence of anticompetitive conduct.

2. Output Gap

The output gap is another metric we use to evaluate Duke's generation dispatch. The output gap is the unloaded capacity of an available generation resource when the prevailing market price exceeds the marginal cost of producing from that unit by more than a specified threshold. We use $25/MWh and $50/MWh as two thresholds in our analysis. Hence, at the $25/MWh threshold, if the prevailing market price is $60/MWh and a unit with marginal costs of $40/MWh is unloaded, then we do not consider this part of the output gap because the marginal cost plus the $25/MWh threshold is greater than the $60/MWh market price. However if the marginal cost is $30/MWh, we would consider it in the output gap at the $25/MWh threshold, but not under the $50/MWh threshold.

Figure 14 below shows the minimum daily output gap for the peak hours (hour ending 7 AM through hour ending 10 PM). The minimum is shown because the most liquid market is for a sixteen-hour block, and enough units must be committed to meet the peak hour of demand. As a result, it is necessary to keep some of the required units at part load during the hours with lower demand, resulting in an increase in the output gap. Only units that are committed during the day are included in the daily calculation. Hydro and nuclear units are also excluded.

For this analysis, we normally define the market price as the minimum between the Platts published VACAR day-ahead price (discussed above) and the average PJM real-time price at the AEP hub for the on-peak hours of the day. We chose this composite price to ensure that if a portion of a unit's capacity were included in the output gap both day-ahead and real-time prices were taken into consideration. Theoretically, dispatch should be driven by real-time prices, but the timing of natural gas nominations and the limited liquidity in the real-time markets cause the day-ahead market to also be important for dispatch. The minimum daily output gap is used in the analysis, because this represents the quantity of power that could have been sold profitably on a sixteen-hour on-peak block schedule without having to commit additional units. However, for this quarter, an output gap did not occur using the composite prices even at the $25/MWh threshold, because the VACAR prices were consistently low. Because of this, we only used the PJM prices for this quarter.

Figure 14: Minimum Daily Output Gap
October 2008 – December 2008

Redacted

The figure shows that an output gap occurred on three days at the $25/MWh threshold, based on just the PJM prices. The figure also shows the PJM and VACAR prices. The maximum output gap is 7 MW which is insignificant. Accordingly, we do not find evidence of anticompetitive conduct through the withholding of generation.

3. Generator Availability

We evaluate generator availability by examining the amount of capacity on outage as well as the ratio of capacity on outage to total capacity. Our first analysis is in Figure 15. We compare the average capacity on outage as well as the VACAR price and the prices at which Duke made real-time sales.

Figure 15: Outage Quantities
October 2008 – December 2008

Redacted

The figure shows that Duke sales prices and the market (VACAR) price are generally well correlated. Some differences are expected because the Duke sales prices reflect real-time transactions while the wholesale prices reflect day-ahead transactions. Our main interest is in generation outages that cause increases in market prices. Planned outages were minimal over the quarter until we move out of the summer peak period in late September. The correlation between unplanned outages and prices is not immediately apparent from the chart. Therefore, we present statistics that help clarify the relationship below, in Figure 17.

Figure 16 shows the average ratio of capacity in outage to total capacity (i.e. the average outage rate) and the VACAR price and the Duke short-term sales price. This chart reveals patterns similar to that revealed in Figure 15. The average forced outage rate over the study period was approximately [redacted] percent, which is [redacted] by industry standards.

Figure 16: Outage Rate October 2008 – December 2008

Redacted

Finally, the correlations of the average outage rates to the VACAR price and the short-term sales price are shown in Figure 17.

Figure 17: Correlation of Average Outage Rates with Wholesale Energy Prices October 2008 – December 2008

	Correlation with VACAR Index	Correlation with Duke Real Time Sales Prices
Planned Outages	48%	37%
Unplanned Outages	-26%	-11%

While the figure reports both planned and unplanned outages, the unplanned ones are the most important from a market power perspective. Planned outages are expected and generally are scheduled in off-peak periods. Unplanned outages can occur during peak times. The negative correlation of the planned outage rate with VACAR index price is expected given that planned outages are typically scheduled during off-peak periods when prices are lower. There was also a negative correlation of the unplanned outage rate with the VACAR index price.

Based on the results, we find no evidence that generation outages were associated with anticompetitive conduct.

C. Analysis of Transmission Availability

Transmission outages are reviewed in order to determine whether they limit market access and, if so, whether they are justified. There were 997 transmission outages that affected power flows on elements at 100 kV and higher during the period of study. We reviewed these outages with a focus on conditions that would have reduced export capability from Duke to CPLW, on the days when the TTC was reduced and the ATC was near zero as shown in Figure 6, and on the days when Duke may have benefited from curtailments as shown by Max Effect in Figure 11. We also reviewed transmission outages that led to the curtailments. Below is a summary of the transmission outages that had a potentially significant effect on the conditions in question.

- [redacted]: This 12-hour planned outage occurred on [redacted], causing schedule curtailments on the "Duke to PJM" and "PJM to SOCO" paths. The outage was [redacted]
- [redacted] This 12-day outage started [redacted], contributing to a reduction in [redacted] The outage was [redacted]
- [redacted]: This 11-day outage started on [redacted], contributing to a reduction in TTC [redacted], 2008. This outage was taken [redacted]
- [redacted] This 3-day outage started on [redacted] The [redacted]
- [redacted] This 2-day outage started on [redacted] The outage was taken [redacted]

Based on our review of these outages, we find the above outages to be legitimate. Accordingly, our analysis of transmission availability did not indicate that Duke reduced market access through unjustified transmission outages.